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The techno-economics of alternative CO_2 transport systems and their application in the Canadian oil sands industry

Guillermo Ordorica-Garcia*, John Faltinson, William (Bill) D. Gunter

Alberta Research Council, 250 Karl Clark Rd., Edmonton, AB, T6N 1E4, Canada

Abstract

The rise in GHG emissions from the oil sands industry has prompted government and industry to seek ways to reduce its CO_2 output. CCS is currently the leading option in Alberta. A key to making it viable is a system that allows multiple emitters to gather, capture, and transport their CO_2 to the best sinks, efficiently and economically. The oil sands are located in Northern Alberta. Geological formations suitable for CO_2 storage exist in the South-West region, ~400 km from the sources. Implementing CCS will necessitate transporting roughly 30 megatonnes of CO_2 to suitable sinks. One of the best sinks is the underground aquifer in the Redwater Reef near Ft. Saskatchewan, with an estimated preliminary capacity of one gigatonne of CO_2, or 37 years of CO_2 emissions from oil sands, at 2007 rates. In this study, we compare two schemes to transport CO_2 from oil sands operations by capturing CO_2 and: 1) transporting it in its supercritical state to storage in the Redwater Reef and 2) transporting it in solution to Redwater, regenerating the solvent on-site and storing the CO_2 in the Redwater Reef.

The fugitive emissions of Case 1 are consistently higher than those of Case 2. This is due to the former's electricity demands and the fact that the emissions associated with energy for solvent regeneration are not captured. Case 1 is more susceptible to electricity cost fluctuations than Case 2, but the latter is more susceptible to changes in the price of fuel. Although the CAPEX is similar for both, Case 2 benefits more from economies of scale than Case 1; the OPEX for Case 1 is 3.5% higher. The avoidance costs of Case 2 are lower on a gross basis (111 vs. 114 \$/tonne CO_2) and on a net basis (327 vs. 851 \$/tonne CO_2).

Keywords: Alberta; oil sands; Canada; regeneration; oxyfuel; pipeline; CO_2 avoidance

1. Introduction

The largest oil sands operations are located in the Fort McMurray area, in Northern Alberta, 300-500 km from geological formations suitable for underground storage in the South-West region of the province. CCS implementation in the oil sands industry will involve transporting megatonnes of CO_2 to such sinks, yearly [1]. The underground aquifer in the Redwater Reef in Ft. Saskatchewan, with an estimated preliminary capacity of one gigatonne of CO_2 [2] is one of the best sinks, as well as potential CO_2 EOR (Enhanced Oil Recovery) site.

* Corresponding author. Tel.: +1-780-450-5473; fax: +1+780-450-5083.
E-mail address: ordorica@albertainnovates.ca.

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In this study, we compare two alternative schemes to capture and transport CO_2 from oil sands operations in Ft. McMurray to storage in the Redwater Reef in Ft. Saskatchewan, Alberta, via pipelines:

1. Capture CO_2 in Ft. McMurray and transport it in supercritical state via pipeline for storage in the Redwater Reef in Ft. Saskatchewan
2. Capture CO_2 in Ft. McMurray and transport it in solution via pipeline to Ft. Saskatchewan. Regenerate the solvent on-site and store the CO_2 in the Redwater Reef

Option 1 is the most commonly cited solution for CCS implementation in Alberta. This "business as usual" scheme features substantial costs and complexity, but it falls under an existing regulatory framework and it is backed by significant experience with acid gas transport and injection in the province. Option 2 is an innovative approach to the development of a CCS network for the oil sands industry and the key contribution of this study.

This novel solution for CO_2 transport in the oil sands industry incorporates three main concepts: 1) CO_2 transport in-solution, 2) centralised solvent regeneration at the CO_2 storage site, and 3) oxyfired steam generation for solvent regeneration. The concept is known as Remote Centralised Solvent Regeneration (RECSOR). The study is an initial techno-economics comparison of RECSOR vs. the business as usual approach as the basis for a CCS network in the oil sands industry. The analysis is based on capturing CO_2 from oil sands operations in Ft. McMurray assuming CO_2 production rates corresponding to forecasted oil sands production in the year 2020. The main goal of the project is to compare the costs of RECSOR with those of a base case (business as usual) scenario by performing a techno-economic assessment (± 50% accuracy estimate).

2. Methodology

This study presents two cases, one involving a "business as usual" CCS system base case, and the RECSOR CCS concept, all based on our previously estimated CO_2 production rates from bitumen extraction rates corresponding to the year 2020 [3]. Figures 1 and 2 illustrate the base and RECSOR cases respectively.

Case 1: Base Case. This case involves large mined and SAGD bitumen producers individually capturing CO_2 in Fort McMurray and transporting it in its supercritical state via pipeline to storage in the Redwater Reef. The flue gas produced must be first pressurized in a large blower before entering the CO_2 absorber. The CO_2-rich amine solution is then regenerated in a stripper. The regenerated amine is sent back to the stripper, while the recovered CO_2 (stream 6 in Figure 1) is compressed to supercritical state. The combined CO_2 from each individual oil sands producer is then piped to the Redwater reef. The CO_2 pipeline features enough booster compressors to meet the required injection pressure at the storage site. All of the compressors and the blower are driven by electricity purchased from the grid, while the energy for CO_2 recovery is supplied by natural gas-fired furnaces.

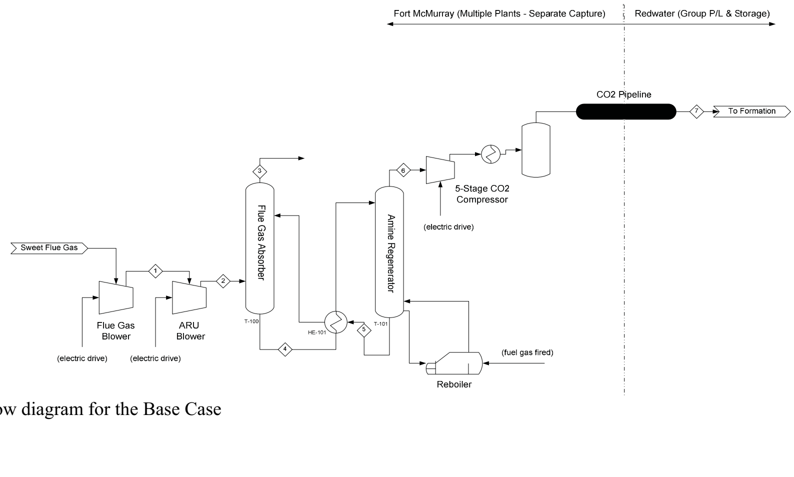

Figure 1. Process flow diagram for the Base Case

Case 2: RECSOR. In this scenario, CO_2 is captured by individual bitumen producers and transported to the Redwater Reef in solution with amine, whereby all of the CO_2 is recovered using large amine regeneration systems. Similar to the base case, the flue gas is initially pressurized before entering the CO_2 absorber. The combined CO_2-rich amine from all of the absorbers is then piped to the Redwater reef, passing through booster stations. At Redwater, the amine is regenerated in a large stripper (unit T-101 in Figure 2) and then transported back to Fort McMurray using a second pipeline. RECSOR features a natural gas oxy-fired boiler that generates high pressure steam, which is used to drive the CO_2 compressors. The LP steam coming out of the compressors is then sent to the amine reboiler, providing all of the required energy for solvent regeneration. Most of the compression power required is supplied by expanding the HP steam, with the balance supplied by purchased electricity. Purchased electricity is also required to drive the flue gas blower and the pumps in the booster stations along the solvent pipelines. The CO_2 produced in the oxy-fired boiler is combined with the CO_2 recovered in the absorber and compressed prior to injection into the Redwater Reef.

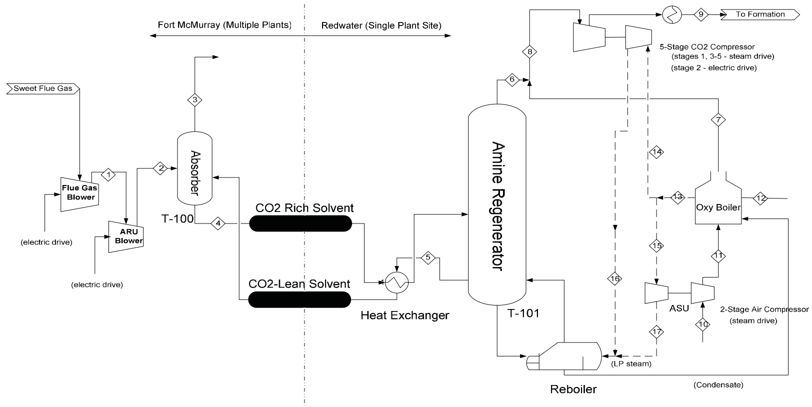

Figure 2. Process flow diagram for RECSOR

Process and economic calculations for the project utilized our in-house "Integrated Economic Model" (IEM) for CO_2 capture, compression, transport and storage [4]. The IEM models the entire CCS chain by solving for material/energy balance data and equipment power demands from a CO_2 capture plant and a CO_2 transport pipeline. The main inputs to the IEM are CO_2-bearing gas volumes and compositions derived from carbon-emitting sources (i.e., fossil power plants, boilers, etc.). Its outputs include mass/energy balances, capital and operating costs of CO_2 capture facilities and pipelines, and CO_2 avoidance costs. The capital costs of all the required equipment are calculated based on CO_2 volume throughput, using vendor quotes and publically available equipment costs. Operating costs are mainly a function of fuel consumption for reboiler heat and compression/pumping power. Fixed operating costs for labour are based on plant size and complexity and other fixed costs are a fixed percentage of major equipment costs. The IEM also calculates CO_2 avoidance costs for the "gross" volume of CO_2 captured (i.e., CO_2 in inlet flue gas) as well as "avoided" CO_2 volume (gross CO_2 volume minus all fugitive CO_2 emissions).

2.1. Assumptions

The analyses considered future SAGD and mining operations (without upgrading) producing over 100k barrels of bitumen per day in the Fort McMurray area. These are the most challenging sources of CO_2 to capture, due to their large flue gas volumes at low concentrations. Further, the bulk of the growth in future CO_2 emissions in Ft. McMurray will come from SAGD operations [3]. Hence, our analysis tests RECSOR against the conventional approach for CCS under a very taxing scenario. Table 1 shows the estimated flue gas production used in the study.

The flue gas production in the analysis includes hot water, steam, and power production, and excludes flue gas associated with mobile equipment, fugitive emissions, etc. Post combustion capture, using KS-1 solvent with a capture rate of 90% is assumed. The assumed composition of the flue gas from mining is: 5.3% CO_2, 13.2% O_2 and 81.5% N_2 (mol %, dry). SAGD flue gas composition is 6.3% CO_2, 12.7% O_2 and 80.9% N_2 (mol %, dry).

The CO_2 is transported 350 km from Fort McMurray area to the Redwater Reef. In the base case, the supercritical CO_2 arrives at Redwater at ~9 MPa via a single pipeline and passes through a booster station, emerging at 15 MPa. In the RECSOR case, the CO_2 is carried in solution with KS-1 and goes through two pumping stations, arriving to Redwater at a pressure of 15 MPa. There are two pipelines in the RECSOR case: one for CO_2-rich solvent running from Ft. McMurray to Redwater and a return pipeline for the regenerated solvent going the opposite way. Natural gas is used in all boilers and furnaces (LHV = 37.7 MJ/m^3) and electricity is purchased from the grid. CO_2 emissions factors are 700 kg/MWh for gas and 801.6 kg/MWh for electricity. The latter factor corresponds to a weighted average of Alberta's power grid, which currently consists of 86% coal- and natural gas-fired power plants [5].

Table 1. CO_2-bearing flue gas production (tonnes/d) from bitumen mining and SAGD operations in Ft. McMurray, 2020 forecast

Producer	Mining	Producer	SAGD
CNRL	54,139	ConocoPhillips	70,131
Imperial	60,155	Encana	199,033
Shell	134,346	Husky	140,263
Syncrude	81,610	Opti-Nexen	148,678
Total E&P	20,052	Suncor	257,382
Suncor	88,428		
Total (mining)	438,729	Total (SAGD)	815,486

The main economic inputs to the analysis are summarised in Table 2. The capital and operating costs are calculated on the basis of these inputs. All costs are estimated using parameters built into the IEM model, with the exception of the pipeline and oxy-boiler capital costs. The former were set as an intermediate value from a range of published pipeline costs [6, 7, 8] and are given in dollars per pipeline diameter per mile of installed pipeline. These values range from 47.4 to 64.2 k$/in/mi whereas this study assumed a cost of 60 k$/in/mi. The oxy-fired boiler capital cost was assumed to be double that of a conventional boiler due to a lack of vendor information for natural gas-fired utility-scale oxyboilers at the time of writing. This is a gap in our analysis that must be improved.

Table 2. Summary of key economic inputs to the IEM

Parameter	Value	Parameter	Value
Plant Life (Years)	25	Maintenance Factor (% of Capital Cost)	1.5
Discount rate (%)	10	Spare Parts Factor(% of Capital Cost)	3.0
Natural Gas ($/MCF)	4.5	Insurance Factor (% of Capital Cost)	0.5
Electricity ($/MWh)	60	Contingency (% of Capital Cost)	10

The pipeline cost is a function of the CO_2 flowrate, as this will determine its diameter. The IEM has the built-in ability to estimate the supercritical CO_2 pipeline costs (Case 1). For RECSOR, we estimated the diameter needed to accommodate the flow of solvent, which yielded the pipeline costs. The RECSOR unit-pipeline installation costs were assumed to be the same as those of supercritical CO_2 pipelines. This value is on the higher end of costs in the literature reviewed but we believe it is not unreasonable given the very large diameter of the solvent pipeline. All costs are given in 2008 USD. The economic analyses exclude costs of: land purchase, project financing, corporate taxes, property/other local taxes as these costs are geographic location- and operating company-specific.

3. Results

Table 3 shows a comparison of energy demands. The energy for the fan/blower and reboiler are identical for both cases as their flue gas and solvent volumes are identical. The CO_2 compression load of RECSOR is higher than that of the base case because of the extra CO_2 captured from the oxyboiler. RECSOR also has large pumping loads due to the combination of larger volume to be transported and the need of two pipelines versus one in the base case.

Table 3. Energy consumption breakdown

Process Unit	Units	BASE	RECSOR
Flue gas blower and fan	MWe	2775	2775
Oxygen plant (ASU)	MWt	-	315
CO_2 compressor	MWe	507	161
	MWt	-	467
Pipeline compressor or pump	MWe	14	112
Reboiler	MWt	3,512	3,512
Ancillaries	MWe	204	218
Total	MWe	3,500	3,266
	MWt	3,512	4,294

As seen in Figure 3, the capture plant is the largest cost component, representing 54% and 48% of the total capital expenditure, for the base case and RECSOR, respectively. For the base case, utilities are the second largest capital expense, at 17% of the total, followed by contingency and pipeline costs, each representing 9% of the total CAPEX. Utilities are high in the base case because of the considerable energy demands of the capture process, due to the massive volumes of flue gas processed and the use of multiple capture plants (i.e., inefficient duplication).

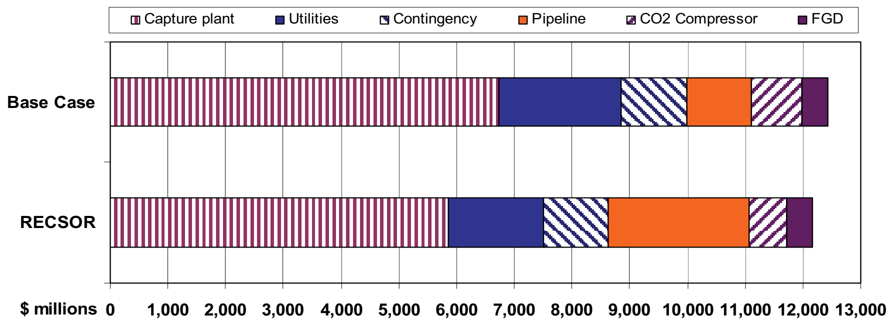

Figure 3. Capital cost comparison

All of the capital components for RECSOR are marginally lower than those of the base case, with the exception of the pipeline, which is twice as expensive as the base case pipeline. The reason for RECSOR's lower CAPEX is that the cost of the stripper and the utilities required for solvent regeneration benefit from economies of scale due to consolidation of the large CO_2 volumes involved. RECSOR capital costs may be potentially lower than what this study suggests because its pipeline and oxy-boiler costs are most likely overstated. For the pipeline, we assumed 600 ANSI carbon steel (1480 psi maximum pressure -1200 psi operating), suitable for supercritical CO_2 transport, yet it is used to transport rich amine solution (60% water) at low pressure. We did not explore alternative pipeline types for the solvent (e.g., concrete, plastic, low-pressure, etc.), that may be suitable for RECSOR, with lower cost.

The operating costs are depicted in Figure 4. The variable costs, electricity and fuel gas represent over 75% of the total. Electricity is the largest cost, due to the high compression loads, particularly in the ARU flue gas blower. RECSOR produces some of its power internally, by using HP steam to drive compressors, offsetting purchases from the grid. Fuel gas expense is also large due to the energy demands for solvent regeneration. RECSOR has higher fuel costs because more steam is required to drive compressors and to supply heat for solvent regeneration. Maintenance is the largest of the fixed costs as it is a function of capital costs, which are fairly elevated. RECSOR operating costs are 3% lower than those of the base case ($2,989 million vs. $3,092 million).

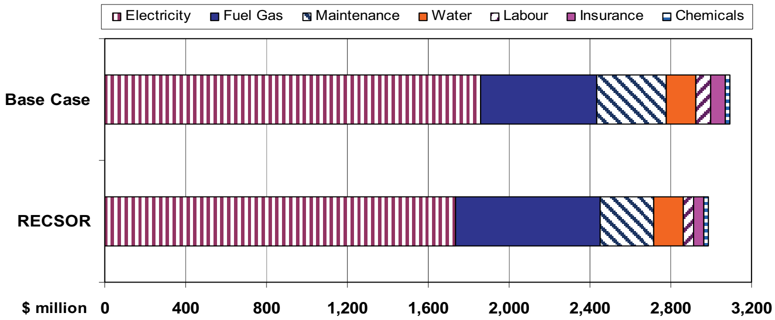

Figure 4. Operating cost comparison

The net and gross CO_2 capture costs are summarised in Table 4. On a gross basis, the carbon capture costs of RECSOR are 3% lower than those of the base case. Once the fugitive CO_2 emissions (due to power generation, fuel gas burning, etc.) are considered, the avoidance costs of RECSOR are 62% less than those of the base case. This is simply a reflection of the base case's lower net CO_2 capture (13%) compared to RECSOR (34%). The daily net CO_2 avoidance of RECSOR is 37.4 ktonnes compared to 14.7 ktonnes for the base case. The avoidance figures presented here include CO_2 capture and transport and exclude the storage component. The reader must note that our values would vary slightly once the extra costs and fugitive emissions associated with site-specific storage are considered.

Table 4. CO_2 avoidance cost comparison

Parameter	Units	Base Case	RECSOR
Gross CO_2 capture cost	\$/tonne CO_2 captured	114	111
Net CO_2 avoidance cost	\$/tonne CO_2 avoided	851	327
Net CO_2 avoidance	% of total emitted	13.4	33.9

To better understand the differences in gross and net avoidance costs, Figures 5 and 6 show the breakdown of the CO_2 emitted and captured for each case, according to source. The total CO_2 emissions from oil sands operations are 110.4 ktonnes/day. In both cases, 90% of this CO_2 is captured, resulting in fugitive emissions of 11 ktonne/day. Implementing CO_2 capture results in additional CO_2 emissions from power generation, of 66.4 ktonnes/day for the base case and 61.9 ktonnes/day for RECSOR. The fundamental advantage of RECSOR is that all of the 22.7 ktonnes/day of CO_2 generated to supply heat for solvent regeneration is captured, as seen in Figure 6, unlike in the base case, where 18.2 ktonnes/day of CO_2 are released to the atmosphere.

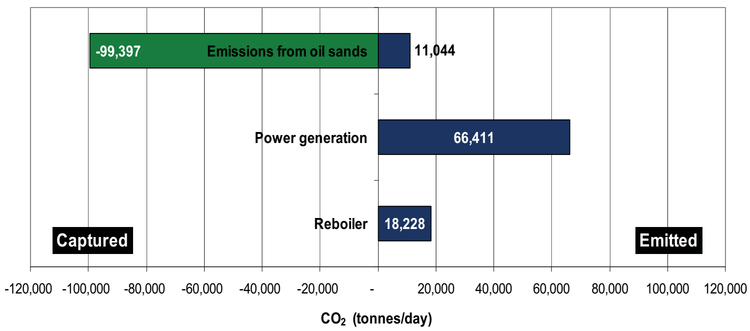

Figure 5. CO_2 emissions distribution – Base case

Our results suggest is that in emissions reductions terms, RECSOR offers a clear advantage over the base case. From a gross avoidance perspective, RECSOR features 2.5 times more CO_2 avoidance than the Base Case, for 3% less cost. On a net basis, although the $/tonne CO_2 costs are substantially higher than on a gross basis, RECSOR has the potential to offer CO_2 avoidance for less than one half the cost of the base case, which relies on supercritical CO_2 transport and CO_2 capture and regeneration in individual plants.

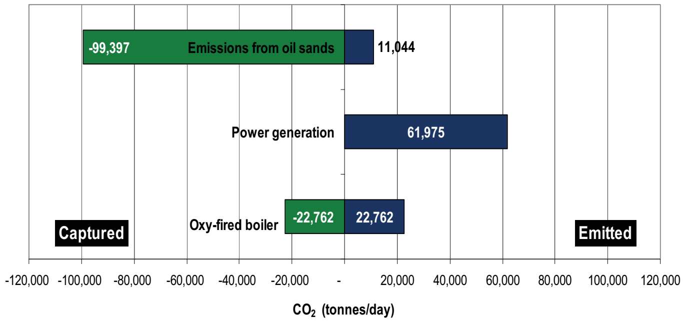

Figure 6. CO_2 emissions distribution – RECSOR

4. Future work

This work is an initial attempt at establishing the advantages of RECSOR over the currently leading system for CCS implementation in the oil sands industry (i.e., based on supercritical CO_2 transport). As such, the accuracy of our cost estimates was limited to ±50%, which is adequate to meet the goals of the study. Our study has shown that the RECSOR concept merits further investigation, to refine and fully detail its techno-economic advantages/features over competing alternatives for CCS implementation in Alberta. Future work will focus on the following areas:

1. **Improve RECSOR pipeline cost estimation** – a follow-up study will investigate various alternatives for the types of high volume pipelines that may be suitable for transporting CO_2 in solution with amine/water blends at low pressure. Pipelines similar to those used for water transport may be a good fit for RECSOR, or other alternatives to carbon steel pipelines must be evaluated. The study will take into account the properties of the solvent (density, corrosivity, etc.) and determine the optimal type and size of pipelines required for the rich solvent and lean solvent segments. Its outcomes will become inputs to the IEM thus enabling us to refine the CAPEX, OPEX, and CO_2 avoidance costs presented here.

2. **Run additional cases** – in this study, only CO_2 emissions from large mining and SAGD operations were considered. These are the most challenging sources of CO_2 for CCS. We will evaluate the techno-economics of RECSOR with higher purity CO_2 sources such as those from upgrading operations. The flue gas from hydrogen plants has higher CO_2 concentrations and lower volumes, which will improve the techno-economics of both the base case and RECSOR. We will evaluate new cases involving capturing CO_2 from: a) hydrogen plants in Ft. McMurray and b) planned upgrading operations in Ft. Saskatchewan. The RECSOR concept applied to the latter case may prove to be a much superior solution to that of the base case, as it would require much shorter pipelines than the Ft. McMurray case, leading to substantial cost reductions.

3. **Combine RECSOR with DMX capture** – IFP is currently developing a process that uses an amine for CO_2 capture which is loaded to a “critical point”, causing a phase separation of ammonium salts [9]. The resulting CO_2-rich phase is separated from the CO_2-lean phase in a decanter, downstream of the CO_2 absorber. The latter is recycled to the absorber while the former is sent to a stripper for thermal regeneration. This process is a perfect match for RECSOR. By regenerating only a portion of the CO_2-loaded amine (the richest in CO_2), the cost of the pipeline, the pumping power and the capital cost of the stripper and the energy required for solvent regeneration could all be substantially lowered, making RECSOR more competitive. We will evaluate the techno-economics of the DMX+RECSOR process, a potential solution for cost-effective CCS implementation in Alberta.

5. Conclusions

The base case features very large fugitive CO_2 emissions, with much lower avoidance than RECSOR (~13% vs. ~32%). The superior CO_2 avoidance capabilities of RECSOR are due to two fundamental factors: 1) its net purchased electricity demands are lower than those of the base case and 2) the CO_2 produced in the oxy-boiler is not emitted to the atmosphere. In the base case, the emissions from energy supply for solvent regeneration are vented, which combined with its fugitive emissions from power generation, largely offset the amount of CO_2 captured. RECSOR, however, has larger fuel gas demands than the base case and is thus more sensitive to changes in the cost of fuel. This is an inevitable trade-off, exchanging greater CO_2 avoidance for larger fuel gas demands. Concerning capital costs: the pipeline is a critical component for RECSOR. Liquid pipeline costs in our study are not as accurate as the other CAPEX elements. Our assumed RECSOR pipeline capital costs may be excessive, due to a likely pipeline technical overspecification stemming from a desire to avoid biased modelling in favour of RECSOR. This study would benefit from further investigation on and improvement in the costing of RECSOR pipelines.

Our study is based on existing technology. For instance, the KS-1 solvent has been proven for CO_2 capture, while pipeline and cryogenic oxygen plants are mature technologies. However, there are a number of developments that will likely improve the techno-economics of the cases presented here, in the near future. Efforts are underway to produce new solvents for CO_2 capture, with lower regeneration energy. Likewise, the development of improved CO_2 absorption and regeneration designs and integration schemes hold great promise for further lowering energy demands. If these developments reach a commercial stage, they would improve the techno-economics of the systems presented here. RECSOR, however, would benefit substantially more, due to its superior solvent regeneration and its already lower capture capital and operating costs.

RECSOR would benefit further from advances in oxyfuel and oxygen separation technologies. Oxyfuel boiler development focuses on attaining smaller boiler sizes by reducing (and eventually eliminating) flue gas recycling. Smaller boilers would lead to substantial capital cost reductions whereas the elimination of flue gas recycling would mean lower energy demands. Concerning oxygen separation, improved integration in cryogenic plants has the potential to attain energy demand reductions of roughly 20%. Ion/oxygen transport membranes have strong potential to lower the energy demands of oxygen production by as much as 33% with respect to cryogenic units. These two developments would further lower the costs and energy demands of RECSOR, making it even more competitive.

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